# GENERAL INSTRUCTIONS FOR DEMAND FORECAST SUBMITTALS

## BACKGROUND

To develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety, the California Energy Commission (Commission) is directed by Public Resources Code (PRC) Section 25301 to conduct regular assessments of all aspects of energy demand and supply. These assessments serve as the foundation for analysis and policy recommendations to the Governor, Legislature, and other agencies in the *Integrated Energy Policy Report (Energy Report)*. To carry out these assessments the Commission may require submission of data from market participants in California:

> To perform these assessments and forecasts, the Commission may require submission of demand forecasts, resource plans, market assessments, and related outlooks from electric and natural gas utilities, transportation fuel and technology suppliers, and other market participants. PRC 25301(a)

The Commission is preparing to undertake assessments for the *2005 Energy Report*. The adopted forecast, or range of forecasts, will provide a foundation for the analysis and recommendations of the *2005 Energy Report*, including resource assessment and analysis of progress towards energy efficiency, demand response and renewable energy goals. The forecasts will also serve as a reference case in the California Public Utilities Commission (CPUC) 2006 procurement plan proceeding and in the 2005 California Independent System Operator (CAISO) controlled grid study. Commission demand and supply assessments are also used in the *California Gas Report*.

To provide the Commission and the public with the opportunity to consider a range of perspectives on demand futures, the Commission is requesting electricity demand forecasts, demand-side management impacts, and related information from all load-serving entities (LSEs) with load greater than 200 megawatts (MW). These submittals are to be prepared and documented according to the attached instructions. Separate documents will direct the contents and format of other resource planning information. Definitions of terms used in the instructions are found at the end of this document.

## Summary of Requested Data

Form 1. Historic and Forecast Electricity Demand – annual consumption and peak demand, private supply, and hourly loads

Form 2. Forecast Input Assumptions - economic and demographic assumptions and electricity rate forecasts
Form 3. Demand Side Management (DSM) Program Impacts and Costs (Committed and Uncommitted), including demand response and distributed generation program impacts
Form 4. Forecast Methodology Documentation
Form 5. DSM Methodology Documentation (Committed and Uncommitted)
Form 6. Uncertainty Analysis

## Submittal Format

Parties are requested to submit a diskette or compact disk containing:

- data from Forms 1, 2, and 3, and
- reports on Forms 4 through 6 in Word or Acrobat.

To:

California Energy Commission
Docket Office
Attn: Docket 04-IEP-01
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

To expedite the forecast comparison and review process, an Excel template with formats for each form in 1, 2, and 3 is provided. While it is preferred that filers use this template, participants may provide these results in their own format as long as the equivalent information is provided and the information is clearly labeled.

## Due Dates

| Forms: | Must be submitted to the Commission on or before: |
|---|---|
| 1, 2, 4, and 6;<br>3 and 5 – Committed | February 1, 2005 |
| 3 and 5 – Uncommitted | March 1, 2005 |

The data do not have to be distributed to the *Energy Report* service list.

## Who Must File

Statutes found in the Public Resources Code and supporting regulations give the Commission authority to require forecast submittals from all entities engaged in generating, transmitting, or distributing electric power by any facilities. This includes are traditional investor-owned utilities, municipal utilities, energy service providers permitted to operate under applicable law, community choice aggregators permitted to operate pursuant to AB 117, and all other entities that serve end-use loads, collectively referred to here as LSEs. However, according to existing regulations, small LSEs[1] need not comply with the complete reporting requirements, but may be required to submit demand forecasts in an alternative abbreviated format established by the Commission. For this specific 2005 *Energy Report* proceeding the Commission is not requesting data from any LSE with peak demand less than 200 MW.

Not all required forms may be applicable to all parties. For example, energy service providers (ESPs) may have no energy efficiency program impacts to report. To account for differences in business practices, some forms are required only of distribution utilities (those who own and/or operate an electric distribution system), while others are required of *all* LSEs (including distribution utilities). The table below shows form-by-form filing requirements.

| | | **Who Should File:** | |
|---|---|---|---|
| | | **Non-Distribution LSEs** | **Distribution Utilities** |
| Form 1.1 | Retail Sales Of Electricity By Sector | x | x |
| Form 1.2 | Sales Including Departing Load | | x |
| Form 1.3 | Net Electricity For Generation Load | | x |
| Form 1.4 | Coincident Peak Demand By Sector | x | x |
| Form 1.5 | Distribution Area Peak Demand | | x |
| Form 1.6 | Hourly Loads | x | x |
| Form 1.7 | Local Private Supply By Sector | | x |
| Form 1.8 | Peak Demand Weather Scenarios | | x |
| Form 2.1 | State or National Economic and Demographic Inputs | | x |
| Form 2.2 | Planning Area Economic and Demographic Assumptions | | x |
| Form 2.3 | Electricity Rate Forecast and Natural Gas Price Forecast | x | x |
| Form 2.4 | Customer Count & Other Forecasting Inputs | x | x |
| Form 3.1 | Efficiency Program First Year Costs and Impacts | x | x |
| Form 3.2 | Efficiency Program Cumulative Impacts | x | x |
| Form 3.3 | Renewable And Distributed Generation Program Costs and Impacts | x | x |
| Form 3.4 | Demand Response Program Costs and Impacts | x | x |
| Form 4 | Demand Forecast Methods And Models | x | x |
| Form 5 | Demand-Side Program Methodology | x | x |
| Form 6 | Uncertainty Analysis | x | x |

[1] A small LSE is one which has experienced a peak demand of 200 megawatts or less per year in both of the two calendar years preceding the required data filing date and is owned or operated by a public government entity or regulated by the California Public Utilities Commission.

## Confidentiality

Certain categories of data submitted to the Commission are eligible for automatic designation of confidentiality. The types of information that are eligible and the process for obtaining this designation are found in Section 2505(a)(5) of the Commission's regulations (found in Title 20 of the California Code of Regulations). Data that is not included in these categories but which the filer believes is entitled to confidential treatment should be submitted with an application for confidential designation so that the Executive Director can review the information and make a determination about its confidential status. In addition, filers should be aware that some confidential data may be disclosed after aggregation by Commission staff. Energy sales data is automatically public if reported at the following levels:

- For individual electric service providers, data aggregated at the statewide level by major customer sector;
- For the sum of all electric service providers, data aggregated at the service area, planning area, or statewide levels by major customer sector;
- For the total sales of the sum of all electric retailers, data aggregated at the county level by SIC or NAICS.

# PROTOCOLS FOR SUBMITTED DEMAND FORECASTS

In general, the demand forecast submitted should be the most likely projection of unmanaged total consumption. Unmanaged consumption means that the forecast should not include uncommitted DSM and total consumption means that the forecast should include total electricity usage irrespective of source, although locally supplied energy is reported separately from sales. Because one use of these forecasts will be to provide a basis for resource assessments, total consumption at the end-user level must be adjusted by losses to reflect total usage at the generation level. Since local private supply reduces system requirements and losses, forecasts of local private supply are also required from distribution utilities.

General instructions on how the forecast is to be prepared:

1. Forecasts are to project expected electricity demand for the years 2005-2015. The last historic year for most data will be 2003. Data for 2004 should represent the LSE's best estimates available at the time of filing.

2. Load serving entities are to prepare demand forecasts for their expected retail customers. To determine whether major discrepancies exist between the distribution utility and non-utility submittals, distribution utilities are to provide forecasts for the complete load in their distribution service areas, reporting bundled load on Forms 1.1 and 1.4, and total load on Forms 1.2 and 1.5.

3. Distribution utilities are to prepare demand forecasts using either:
   (A) franchise service area defined by applicable state law or regulatory decisions lawfully determined by the California Public Utilities Commission, or

   (B) a definition of distribution utility service area that has been mutually agreed upon by the distribution utility and Commission staff.

4. Utilities serving retail customer demand both within and outside of California are to submit demand forecasts using these Forms and Instructions for the California portion of retail demand, provided that that California portion of peak demand exceeds 200 MW.

5. Impacts of DSM and demand response programs on energy and peak demand should be provided according to the guidelines below:

   Section 1345 of the Commission's regulations (found in Title 20 of the California Code of Regulations) requires that demand forecasts are to account for all conservation "reasonably expected to occur." Since the *1985 Electricity Report*, reasonably expected to occur conservation programs have been split into two types: committed and uncommitted. This demand forecast continues that distinction. Committed programs are defined as programs that have been implemented or for which funding has been approved. Only the effects of committed programs should be included in the demand forecast. For the investor-owned utilities (IOUs), committed conservation programs are those programs included in the 2006-2008 program plans approved in the CPUC Energy Efficiency Rulemaking Proceeding (R01-08-028). Uncommitted programs are those expected or scheduled to begin 2009-2015. For publicly owned utilities, committed means the governing board for a municipal utility has authorized expenditures of funds for at least a preliminary program plan from which impacts can be quantified.

   The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. For this filing, a key distinction is whether or not the program is dispatchable. Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Energy or peak load saved from dispatchable programs is to be treated as a resource, and therefore should not be accounted for in the demand forecast. Nondispatchable programs are not activated using a predetermined threshold condition but allow the customer to make the economic choice whether to modify its usage in response to ongoing price signals. Impacts from committed *nondispatchable* programs should be included in the demand forecast, e.g., load reductions at on-peak hours subtracted from the "base" forecast and load building or load shifting in off-peak hours added to the "base" forecast.

To summarize, parties submitting demand forecasts are required to include the energy and peak impacts of all committed conservation and nondispatchable demand response in these demand forecasts. The impacts of: (1) uncommitted conservation and nondispatchable demand response programs; and (2) committed and uncommitted dispatchable demand response programs, are to be excluded from the demand forecasts but reported in Form 3 as appropriate.

# SPECIFIC INSTRUCTIONS

## 1. Historic and Forecast Electricity Demand

Several forms request data by sector. Definitions of the sectors used in the Commission forecast models are listed in the Definitions section at the end of this document. However, LSEs who use other sectors or customer classes to develop their forecast should modify forms as needed to report the forecast using their own categories, and document their sector or customer class definitions.

**Form 1.1 –to be provided by all load serving entities**
Form 1.1 is for the entry of total retail sales of electricity in gigawatt hours (GWh). All LSEs are required to provide these data, and LSEs selling electricity to customers in multiple service areas should provide these data separately for each service area. Distribution utilities should report only bundled customers in their distribution service areas on this form.

**Form 1.2 –to be provided by distribution utilities**
Form 1.2 is for the entry of electricity sales in GWh by category, where the categories are:

- sales to bundled customers (from Form 1.1),
- sales to direct access customers,
- sales to community choice aggregators (CCAs),
- sales to other publicly owned departing load (such as irrigation districts)

**Form 1.3 –to be provided by distribution utilities**
Form 1.3 adds losses to calculate utility system energy requirements. The first column is transferred directly from “Total Sales” on Form 1.2. Losses entered should represent total transmission and distribution losses, as well as any other unaccounted for losses in the system.

**Form 1.4 –to be provided by all load serving entities**
Form 1.4 accounts for all peak demand by sector as well as for losses. Reported losses should include distribution, transmission, and unaccounted for energy. Peak demand for residential and commercial sectors should be disaggregated into base load or weather sensitive peak demand. All LSEs are required to provide these data,

and LSEs selling electricity to customers in multiple service areas should provide these data separately for each distribution service area.

**Form 1.5 –to be provided by distribution utilities**
Form 1.5 is for the entry of peak demand and losses by category, where the categories provided are:

- peak demand and losses of bundled customers (from Form 1.4),
- peak demand and losses of direct access customers,
- peak demand and losses of CCA entities, and
- peak demand and losses of other publicly owned departing load (such as irrigation districts)

Losses entered should represent total transmission and distribution losses, as well as any other unaccounted for losses in the system.

**Form 1.6 –to be provided by all load serving entities**
This form is for reporting system hourly loads and losses for the last historic year and the forecast period, where MW in each hour reflects end user load, effects of committed demand-side programs, and excludes private supply. LSEs are asked to report total losses for each hour separately. In addition, distribution utilities should report bundled and unbundled loads and losses separately. The template illustrates a preferred data layout; LSEs may submit the data in a text or database format (such as Access) rather than a spreadsheet.

**Forms 1.7a and 1.7b –to be provided by distribution utilities**
Forms 1.7a and 1.7b allow for the reporting of local private supply by sector or customer class, for both annual energy and coincident peak. Private supply includes self-generation, distributed generation on the customer side of the meter, "over-the-fence" sales from a cogeneration facility, or wheeling from a cogeneration facility to a final user.

**Form 1.8 –to be provided by distribution utilities**
This form is for recording peak demand forecasts under high temperature conditions. The cases, referred to as 1-in-5, 1-in-10, and 1-in-20, refer to peak demand under temperature conditions that have a 20 percent, 10 percent, and 5 percent chance of occurring, respectively, relative to normal peak weather. These conditions should be contrasted with the baseline weather condition, which is considered to be a 1-in-2 occurrence or have a 50 percent chance of happening.

LSEs may provide additional forms if they wish to show other categories of energy or peak demand in their filing.

# 2. Forecast Input Assumptions

Electricity demand forecasts are based in part on projections of economic and demographic variables. Forms 2.1 through 2.4 are for the documentation of these forecasting input assumptions. LSEs may provide these variables in their own format as long as the equivalent information is provided and the variables are clearly labeled. The deflator series used to convert variables from nominal to real values should be provided in these forms. If different deflators are used for different variables, each deflator series should be provided.

Documentation of the methods used to develop the economic and demographic projections, including historical data sources, projected data sources, appropriateness of source for forecast and a discussion of the plausibility of those projections are to be included in the Form 4 methodology report.

**Forms 2.1 and 2.2 – to be provided by distribution utilities**

Forms 2.1 and 2.2 are for the documentation of economic and demographic variables as follows:

Form 2.1: National, statewide, and/or regional projections of gross domestic and/or state product, personal income, per capita income, employment, population and aggregate measures of labor productivity, etc.

Form 2.2: Economic and demographic variables having narrower definitions and geographic limits, and which are used directly in an LSE's energy demand forecast models. They may consist of employment and output by industry, local population and population by age groups, households and/or housing by housing type, taxable sales, etc.

All distribution utilities, particularly those with large geographic planning/service areas, should provide any sub-utility regional breakdowns of population and income projections used in the development of the economic, demographic, or energy forecasts. Sub-utility regions may be individual counties, groups of counties and/or weather zones.

It must be emphasized that variables need to be precisely defined. For example, population estimates should be accompanied by an identification of the source of the estimates and whether the estimates are midyear or end of year and whether the estimates are for total population, civilian population, household population, etc.

**Forms 2.3a and 2.3b – to be provided by all load serving entities ~~distribution utilities~~**

Forms 2.3a and 2.3b allow for the reporting of projected energy prices (electricity, and natural gas if used in forecasting) for the sectors used to develop the forecast. Prices should not include city taxes. Electricity prices are to be presented in 2003 cents/kWh. Natural gas prices are to be presented in 2003 $/MMBTU. The deflator series used to convert nominal to real prices, or real to nominal prices, should be provided in these forms for each converted variable.

Where the electricity price projections are derived from a specific resource supply plan, those plans should be documented or referenced. If natural gas prices are used, LSEs are to describe how the projections of natural gas prices were developed. If the natural gas price projections are from a natural gas utility or other source [i.e., Energy Commission, or Public Utilities Commission], note the source and the date of the forecast. Please describe how natural gas prices are converted to sector prices and how price escalation rates are derived.

**Form 2.4 – data to be provided by all load serving entities**

Form 2.4 provides recorded and projected customers counts by major customer sector. These customer counts should reflect end-users with whom the LSE has a generation services relationship. For example, an IOU should not report all customers in its service area, but only the bundled service customers. The most convenient consistent series is acceptable, but a narrative should explain whether the annual values are from a specific point in time, a specific month, an average of months across the year, etc.

**Other Assumptions**

Economic, demographic and energy price projections may not exhaust all variables used by the participant to "drive" the energy demand forecast model(s). For example, small municipal utilities may evaluate such factors as the amount and zoning of undeveloped land within the boundaries of the utility district; local residential, commercial and industrial development policies; local population and income trends; annexation policies; and the General Plan of the municipality. To the extent there are other input assumptions that affect the forecast, it is critical that they be documented. Provide narrative and spreadsheets as appropriate.

# 3. Demand Side Management (DSM) Program Impacts

This section of the forms and instructions summarizes the format requirements for reporting:

- Historic and forecasted energy and peak impacts of conservation, demand response, and distributed generation and renewable programs, both committed and uncommitted.
- Costs of DSM programs.

These data are needed to support evaluation of progress towards achieving state conservation goals, to develop and evaluate forecasts of energy demand, and to evaluate the costs and benefits of using conservation as a resource alternative.

Peak impacts should represent the impact at the time of system peak. Alternatively, LSEs may report average impacts during their peak period. Each LSE should document what the peak impacts represent and which hours they consider their peak period.

All reported impacts should reflect net savings, defined as the change in load attributed to the program adjusted for the effects of free drivers, free riders, state or federal conservation standards, changes in the level of energy service, and natural change effects.

The following forms are to be submitted:

**Form 3.1 and 3.2 – data to be provided by all load serving entities**
These forms are for the recording of costs and impacts of energy efficiency programs. Form 3.1 is for first year impacts and costs by program category and sector 1996-2015, while Form 3.2 is for cumulative impacts.[2] Each program entry should specify whether the program is committed or uncommitted.

These forms request data by program category. IOUs should report by the current CPUC reporting categories:

1. Residential Retrofit
2. Residential New Construction
3. Nonresidential Retrofit
4. Nonresidential New Construction
5. Cross-Cutting
6. IOU Local programs
7. IOU Partnership programs

Other LSEs may use these categories, and add to them as appropriate.

Documentation of the methodology used to estimate impacts for each program should accompany these are to be presented in Form 5.

The following categories are requested for program costs: Administrative, Incentives, Measurement and Evaluation, and Participant cost.

**Form 3.3 – data to be provided by all load serving entities**
Form 3.3 is for the reporting of the costs and impacts of renewable and customer side of the meter distributed generation programs, which would include engine, turbine, microturbine, photovoltaic, wind, and fuel cell technologies. This should include any program that results in displaced utility sales to the end-user through self-generation or distributed generation, but not all distributed generation. Distributed generation that adds power to the grid should be reported in resource plans. Energy and peak impacts should be reported as distributed generation facilities are expected to operate, not as installed capacity or potential energy. Thus

[2] Cumulative savings refers to all savings that can be attributed to a program in a given year. Cumulative savings is equal to current first-year savings plus residual savings from previous year impacts.

there is an interaction with retail electricity rates, fuel prices and how end-users choose to operate these facilities.

**Form 3.4 – data to be provided by all load serving entities**
Form 3.4 should report expected coincident peak impacts for each demand response program. Programs should be identified as committed or uncommitted, and dispatchable or nondispatchable, as discussed in item five in the section on Protocols for Submitted Demand Forecasts.

# 4. Demand Forecast Methods and Models

Each LSE shall document the electricity demand forecast methods and models used to develop the submitted forecast, and shall include a discussion of the following topics.

**Demand Forecast Methodology**
Explain the conceptual basis of the forecast: (1) the energy modeling approach, (2) the definition of customer classes, including which rate classes are included in the categories for which forecasts are submitted, (3) economic and demographic data used, and (4) data sources. Define the area for which the forecast is developed. Identify isolated loads and resale customers and describe how they are included or excluded.

Describe model capabilities in forecasting electricity demand components (end uses, fuel types, structure types, etc.) and key forecast model structural equations (econometric relations, other behavioral equations, and identities). Algebraic variables and computer mnemonics should be defined. For sector models developed using aggregate econometric methods, provide data for the independent and all dependent variables for the entire estimation period. Report all standard statistical parameters for econometric models. LSEs may include existing forecast model reports as an appendix to this form if this report includes a brief summary.

Discuss how the submitted forecast is reasonable in light of economic, demographic, price, and demand-side management trends. Discuss the reasonableness of differences between historic and forecast growth patterns.

Describe the methods and data used to develop the historic and projected peak loads of sectors or customer classes reported in Form 1.4.

**Estimates of Direct Access, Community Choice Aggregation, and Other Departed Load**
Distribution utilities should describe the methods, assumptions, and data used to forecast direct access, community choice aggregation, and other departed load reported in Forms 1.2 and 1.5. This should include a list of current and projected ESP and CCA entities in the distribution utility's planning area.

## Local Private Supply Estimates

Describe fully the methods, assumptions, and data sources used to develop both historic estimates and future projections in Forms 1.7a and 1.7b. Since these are expected energy and on-peak effects, they necessitate estimates of how facilities will actually be operated. Indicate the degree to which conservation efforts, financial incentives, and interruptible programs and negotiated rates have been incorporated into the self-generation forecast. Separate reports may be attached as long as these demand forms include a brief summary.

## Weather Adjustment Procedures

An LSE's energy and peak demand forecasts require adjustment to normal weather conditions. This narrative describes the meteorological parameters used for adjusting and the sources of the meteorological data, including the names and locations of the weather stations used and the weights used for each weather station. LSEs are required to provide baseline values and annual data used in the adjustment process. If heating and cooling degree days or temperature-humidity index (THI) values are used, include the base temperature used in the calculations**.**

LSEs should also describe the methods and assumptions used to develop the high temperature cases (1-in-5, 1-in-10, and 1-in-20) reported in Form 1.8. Provide a narrative discussion of the baseline peak temperature assumptions, how the high temperature scenarios were developed, sources for the weather data, weights for multiple weather stations (if these were used in the analyses), and the methods used to develop the temperature probability distributions.

## Forecast Calibration Procedures

Most forecasts are calibrated to historic energy consumption and peak demand to "scale" the backcast to more closely coincide with historic data. LSEs are required here to provide a comprehensive description of the method of forecast calibration.

The Quarterly Fuel and Energy Report (QFER) system is the principal source of data on historical sales of electricity by economic sector for the Energy Commission staff's demand forecast calibration procedure. In September 2004, Commission staff will provide each participating LSE with a copy of its QFER sales data on file by sector and two-digit SIC code for the years 1990 through 2003.

## Energy and Peak Loss Estimates

Forms 1.3, 1.4, and 1.5 include estimates losses. Describe fully the method and data sources used to develop historic and forecast energy and peak losses. If the method uses a loss factor, specify what that factor is and discuss if that factor varies by year or by customer sector.

## Economic and Demographic Projections

LSEs are required to provide documentation of the methods used to develop the economic and demographic projections reported in Form 2 and a discussion of the plausibility of those projections. They may include an economic and demographic methodology report as an appendix to this form. Documentation should include historical data sources, projected data sources, and appropriateness of source for forecast.

## 5. Demand-Side Program Methodology

**Efficiency Program Costs and Impacts**

Work papers should be provided to document the estimated load impacts provided. Describe how the peak and energy impacts were calculated. Describe the basis or method used to estimate how first year impacts might change over time. Document the net-to-gross ratios used to convert gross measure or program impacts into net impacts. Describe how the per measure impact estimates were aggregated and how any interactive effects between the measures were estimated or accounted for. List any studies or sources relied on to support these assumptions.

**Demand Response Program Costs and Impacts**

The work papers should discuss how the estimates of peak impacts for each program were derived. Describe assumptions about eligible population, participation rates, price elasticities, and wholesale market conditions and prices used to develop the projections. Describe the methodology used to develop estimates of nondispatchable program impacts. For dispatchable programs, describe what criteria will be used in deciding whether to dispatch and how they will be operated to reduce the peak. For example, will the dispatch signal be sent each year to all or most customers, or only during emergencies, or on days when peak load passes a critical value?

**Distributed Generation Program Costs and Impacts**

The work papers should discuss how the estimates of energy and peak impacts for each program were derived. Describe assumptions about eligible population, participation rates, price elasticities, fuel prices and wholesale market conditions and prices used to develop the projections. Describe what criteria are used in deciding how to model customer decisions to use these facilities in peak shaving or baseload modes.

## 6. Uncertainty Analyses

In additional to the reference load forecast, each LSE is required to address the uncertainty of its future loads. Because each LSE may face unique circumstances, we will not require assessment of a pre-determined set of uncertainties, but rather allow each LSE to identify those it considers most germane to its load forecast. For example, an ESP may be most concerned about regulatory issues that affect its ability to compete to provide retail generation services to end-users. A traditional utility, whether an IOU regulated by the CPUC or municipally-owned, may be more concerned with economic and demographic growth in its service area. LSEs are encouraged to present and discuss implications of major uncertainties for their forecast. Specific topics of interest are:

- Aggregate levels or the mix of economic growth throughout the state and its various subregions.
- Potential rate design changes to better communicate market-based prices and/or actual cost of service, perhaps induced by deployment of advanced metering systems.
- Impacts of core/non-core decisions by the CPUC or the legislature.
- Effects of demand response and possible development of dynamic pricing on future load characteristics.
- Implications of continued drought. To what extent have water conditions already increased demand? Describe assumptions about water conditions and water use trends in the forecast. How would continued drought affect the energy and peak demand forecasts?

Each LSE is expected to prepare a narrative report enumerating and describing these uncertainties and the principal impacts they could be expected to have on that LSE's load forecast. This description should describe the uncertainty; the physical, regulatory or legislative mechanism that might cause it to materialize; the lead-time before which and time interval within which this uncertainty exists; whether the impact is upon the number of mix of customers of the LSE versus the usage per customer of the LSE; the relative impact on the LSE; indicators that can be used to determine whether the uncertainty is materializing; and the relationship to other factors affecting the LSE's future electrical load.

Each LSE is required to prepare and file an assessment of the quantitative impacts of each uncertainty on its annual energy and peak load. No specific assessment method is required. Rather, the LSE is expected to use professional analytic techniques in conjunction with expert judgment. Quantitative impacts relative to the reference load forecast should be reported at two, five, and ten years ahead for each uncertainty. The assessment shall be provided as part of the narrative report about the uncertainties, and the LSE shall provide backup reports and work papers to the Commission.

## DEFINITIONS

Cogeneration: An arrangement whereby a utility or customer-owned facility sequentially produces thermal energy for process heat or space conditioning use and electrical energy for private use, or for sale to an electric utility, or some combination thereof.

Customer Sectors: Customer sectors used by the Commission are defined using the following Standard Industrial Classification (SIC) categories (using the 1987 SIC Manual):

| | SIC | NAICS |
|---|---|---|
| Residential: private households, including single and multiple family dwellings. | (e.g., RE00 - RE23) plus SICs 0001, 0010-0039, 88 | RE00-RE39, 001-003, 814 |
| Commercial | 07, 17, 4214, 422, 50-87 less 7521, 89-91, 9200-9224, 9228, 9229, 9235, 93-95, 9600-9661, 972. | 115, 2331, 326212, 42, 44-45, 48841, 493, 512, 514, 518-519, 52-55, 561, 61, 62 (excluding 62191), 71, 72, 81 (excluding 81293 and 814), and 92 (excluding 92811) |
| Industrial | 10-39 | 11331, 21 and 23 (excluding 22131); 31-33, 511, and 54171 |
| Agricultural | 01-02, 08-09. | 111, 112, 113, 114 |
| Water Pumping | 4940-4941, 4970-4971. | 22131 |
| Transportation, Communication, Utility (TCU) | 40-41, 4210-4213, 4215, 4230-4939, 4949-4969, 4980-4988, 7521, 9700-9711. | 221, 48, 49, 513, 517, 562, 62191, and 92811 |
| Street Lighting | 9225-9227, 9250-9261. | 9225, 9226 |
| Other: | Special customers not fitting into above categories. (Each utility should define) | |

Dollar Denomination: Unless otherwise specified, any dollar denominated variable is to be measured in 2003 dollars.

Distributed Generation: Electricity production that is on-site or close to the load center and is interconnected to the utility distribution system. Backup emergency generation that is not capable of operating in parallel (i.e., interconnected) with the utility is not considered distributed generation. Large generation facilities (e.g., qualifying facilities) that interconnect to the utility at transmission voltages would not be considered distributed generation.

Distribution Utility: A utility that owns and/or operates an electricity distribution system that interconnects end-user loads with a generator serving more than one end-user load or the interconnected transmission grid.

Electricity Consumption: The amount of electricity used to provide energy services through both utility sales and local private supply of electricity.

Load Serving Entity: An umbrella term encompassing all entities that provide generation services to end-use customers, irrespective of whether it owns or operates a distribution system. Examples are traditional investor-owned utilities, municipal utilities, energy service providers permitted to operate under applicable law, community choice aggregators permitted to operate pursuant to AB 117, and all other entities that serve end-use loads.

Local Private Supply: Local private supply is supply from self-generation, customer-owned distributed generation, private sales "over-the-fence" from a cogeneration facility, or wheeling from a cogeneration facility to a final user.

Self-Generation: Any generation of electricity by a final user for his own use, irrespective of the technology used. The portion of cogeneration retained for the customer's own use is self-generation even if this is a small portion of overall facility output.